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Thermal Aspects of Geomechanics and Induced Fracturing in CO_2 Injection With Application to CO_2 Sequestration in Ohio River Valley

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Abstract

Ohio River Valley is considered a potential site for CO_2 storage since it is in close proximity to large CO_2 emitters in the area. In a CO_2 storage project, the temperature of the injected CO_2 is usually considerably lower than the formation temperature. The heat transfer between the injected fluid and rock has to be investigated in order to test the viability of the target formation to act as an effective storage unit and to optimize the storage process.

A coupled flow, geomechanical and heat transfer model for the potential injection zone and surrounding formations has been developed. All the modeling focuses on a single well performance and considers induced fracturing for both isothermal and thermal injection conditions. The induced thermal effects of CO_2 injection on stresses, displacements, fracture pressure and propagation are investigated. Possibility of shear failure in the caprock resulting from heat transfer between reservoir and the overburden layers is also examined.

Displacements will be smaller for the thermal model compared to isothermal model. In the thermal case, the total minimum stress at the wellbore decreases with time and falls below the injection pressure quite early during injection. Therefore, fracturing occurs at considerably lower pressure for the thermal model. The coupled thermal and dynamic fracture model shows that thermal effects of injection could increase the speed of fracture propagation in the storage layer depending on the injection rate. These phenomena are dependent primarily on the difference between the injection and reservoir temperature. An optimization algorithm for injection temperature is discussed based on limiting the maximum fracture length and minimizing the risk of leakage from thermal effects of CO_2 storage while improving the injection capacity.

Incorporation of thermal effects in modeling of CO_2 injection is significant for understanding the dynamics of induced fracturing in storage operations. Our work shows that the injection capacity with cold CO_2 injection could be significantly lower than expected, and it may be impractical to avoid induced fracture development. In risk assessment studies inclusion of the thermal effects will help prevent the unexpected leakage in storage projects. The methodology developed will play an important role in process optimization for maximizing the injection capacity while maintaining the safety of storage.

Introduction

Ohio River Valley, located adjacent to the Mountaineer power plant in New Haven, West Virginia, is considered for saline aquifer geological storage of CO_2. This valley is in a relatively stable, intraplate tectonic setting and the regional stress state is in strike slip to reverse faulting regime with the maximum stress oriented northeast to east-northeast. (Lucier et al, 2006).

Based on current sequestration pilot projects and enhanced oil recovery efforts, evidence suggests that geologic sequestration is a technically viable means to significantly reduce anthropogenic emissions of CO_2 (Solomon, 2006; Preston et al., 2005; Wright, 2007) Once CO_2 is injected, the pressure and temperature of the formation is affected by the mass and heat transfer between the injected and in place fluid. These changes have geomechanical consequences on stresses, displacements, fracture pressure and its propagation. Since injected induced geomechanical effects could lead to formation or reactivation of fracture network, rock shear failure and fault movements which could potentially provide pathways for CO_2 leakage, geomechanical modeling plays a very important role in risk assessment of geological storage of CO_2.

In this paper, the thermal geomechanical effects of CO_2 injection in Rose Run Sandstone aquifer located in Ohio River Valley is studied. This study used the fluid and rock mechanical properties provided by the authors of an earlier publication on CO_2 storage in Ohio River Valley (Lucier et al., 2006). GEOSIM, a fully coupled reservoir flow and geomechanical model (Taurus, 2009) is utilized in this work. The software allows accounting for poroelastic and thermoelastic effects and can model static and/or dynamic fractures.

In order to test the possibility of increasing well injectivity, dynamic fracture propagation was allowed by increasing the injection rate so that the bottomhole pressure exceeds the fracture pressure. The coupled fluid flow and geomechanical model for injecting CO_2 in Rose Run sandstone aquifer has been built in an earlier study by Goodarzi et al (2010). In this study thermal effects of injection are incorporated in the exisiting coupled model. Finally an optimization methodology based on the injection temperature and fracture length is proposed.

Coupled thermal and geomechanical model

The target storage reservoir, Rose Run Sandstone (RRS) aquifer in Ohio River Valley, has an average 30 m thickness and extends from 2355 to 2385 m depth. The initial pressure and temperature of the RRS is 26 Mpa and 63.1 C. The fluid flow is modeled by two-phase flow with dissolution of CO_2 in water. The present work is focused on modeling of CO_2 injection through a single vertical well (below and above fracture pressure) for 30 years. To generate relative permeability data, Van Genuchten (1980) function is used with an irreducible gas saturation of 0.05, an irreducible liquid saturation of 0.2 and an exponent of 0.457. The rest of rock and fluid properties can be found in Goodarzi et al (2010). In order to avoid having initial non-zero shear stresses along the principal directions, all the model grids in this study are aligned along the maximum horizontal (N47E) and minimum horizontal (N43W) stress direction. Figure 1 shows the pressure and stress gradients by depth in Ohio River valley. It is important to note that the horizontal stresses in the injection layer (RRS) are lower than in the surrounding layers. This stress state is very critical when considering fracturing the reservoir layer while preventing fracture growth through upper caprock layers.

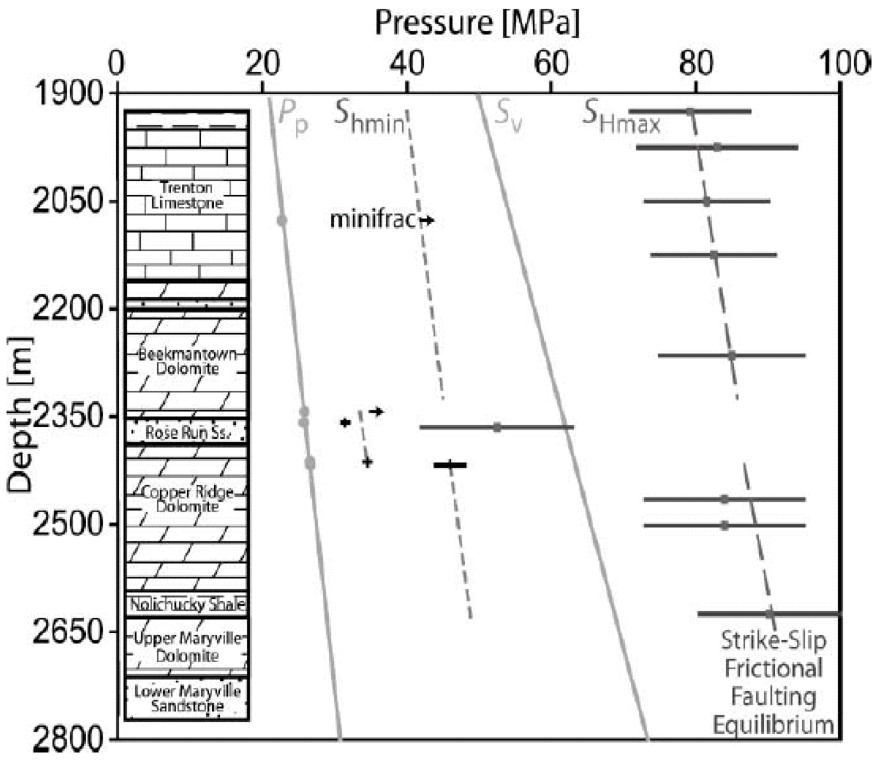


Figure 1: Pressure and stress magnitudes with depth (Lucier et al., 2006)

Since cold CO_2 (at approximately 30 deg C) will likely be injected into the relatively hot Ohio formation (at 60 deg C), thermal effects of injection on fluid flow and geomechanics should be included in the model. The thermal properties used for models in this study are listed in table 1 (Collieu et al., 1975; Fjaer et al, 2008; Guildner, 1958; Lucier et al, 2006; Yaws, 2008)

Table 1: Thermal properties of fluids and rock

	Rock	Water	CO_2
Thermal Expansion Coefficient (1/K)	5.4E-6	2.1E-4	-
Heat Capacity(Kj/Kg K)	0.9	4.182	0.84
Thermal Conductivity(W/ m K)	2.34	0.65	0.084

Thermal effects of injection below fracturing pressure

Injecting cold CO_2 will reduce the stresses in the injection layer and once the temperature front has reached a relatively large area around the wellbore, the reduction in stresses will cause negative volumetric strains which get trasfered to the surface. The surface displacement for the thermal model will therefore fall below that of the isothermal model. Figure 2 compares the vertical displacement at the surface at the well location for the thermal and isothermal model. Thermal models in this paper refer to models having lower injection temperature (30 C) than the reservoir temperature. In isothermal models, injection temperature is equal to reservoir's temperature (60 C).

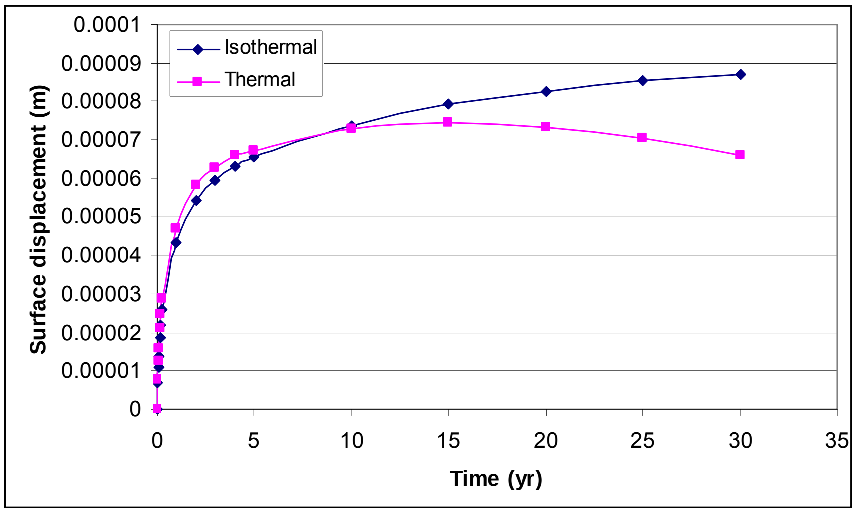


Figure 2: Surface displacement (m) for the well block at surface for the thermal and isothermal model in the case of injection below fracture pressure (35 Mpa) with constant bottomhole pressure of 32 Mpa

One of the most important effects of injection of cold CO_2 is on the fracture pressure. Cooling of the formation reduces the total stresses and therefore lowers the fracture propagation pressure. This reduces the pressure differential available for injection, and therefore injectivity. In the case of injection at fracturing conditions, the fracture propagation pressure will decrease and, if the same injection rate is used, this will accelerate fracture propagation. Figure 3 shows the variation of the total minimum stress and pressure for injection below fracture pressure for both isothermal and thermal case. In both cases, injection was forced at constant pressure below the initial minimum stress, but fracture propagation was not allowed in the modeling. As it is seen, the total stress falls below the pressure for the thermal model at quite early injection times which means that minimum effective stress will reduce beyond zero. Therefore, although CO_2 is injected below the original fracture pressure, fracture would initiate in the thermal model. It is important to stress again that the stress magnitudes after the indicated onset of fracturing are not valid. However, this comparison demonstrates how quickly the fracture propagation can be reached.

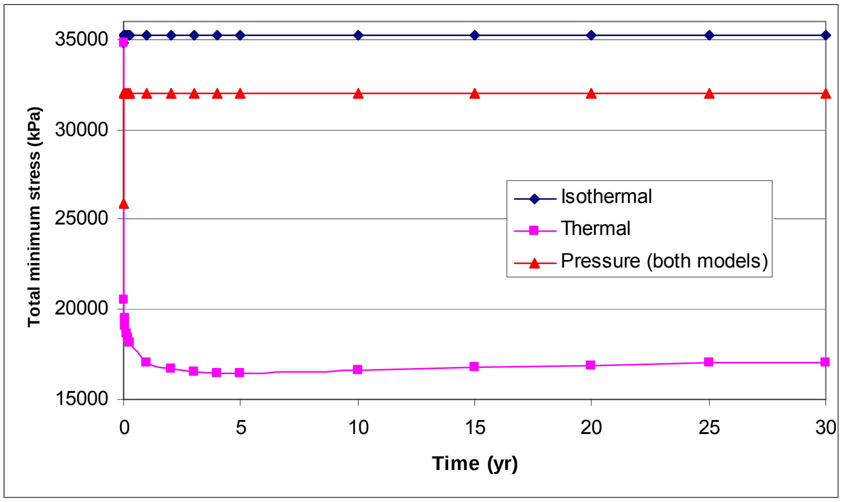


Figure 3: Total minimum stress and pressure history for the wellblock at reservoir's topmost layer in the case of injection below initial fracture pressure (35 Mpa) with constant bottomhole pressure of 32 Mpa

Thermal effects on dynamic fracturing

Thermal effects of injection on the dynamic fracture can be seen by studying the fracture length, vertical growth and fracture propagation pressure. In order to study the thermal effects of injection on fracture propagation, the coupled geomechanical and thermal model was run with a constant injection rate increased to 7.2E4 m^3/day so that the bottomhole pressure reaches the fracture pressure. An effective-stress-dependent transmissibility multiplier function was dynamically computed for a plane of grid cells extending from the wellblock which was designated as the potential fracture plane (see Goodarzi et al., 2010 for details). This will model the effect of fracture on fluid flow and heat transfer, which will in turn change the stresses around the fracture through poroelasticity and thermoelasticity. The isothermal dynamic fracture model properties and the transmissibility multiplier function are described in Goodarzi et al (2010). The boundary conditions of this model were initially constant pressure in order to have a comparison with the models in Goodarzi et al (2010). The dynamics of the fracture propagation is complex as it depends on both poroelastic and thermoelastic effects on stresses. Figure 4 shows the fracture length and well block pressure for thermal and isothermal injection of CO_2 with 7.2E4 m^3/day with constant pressure boundary condition. Well block pressure is very close to the bottomhole injection pressure. As expected, for the isothermal model, due to pressure support from boundary blocks, once the pressure front reaches the boundary of the model (constant pressure condition), the boundary pressure support and increased gas relative permeability in the free gas zone lead to reduction of pressure in the fracture and shrinkage of fracture length. However, in the thermal model due to reduced temperature area around the wellbore, even with the boundary pressure suuport, thermal stresses are reduced around the wellbore and the fracture length remaines almost constant after 5 years of injection.

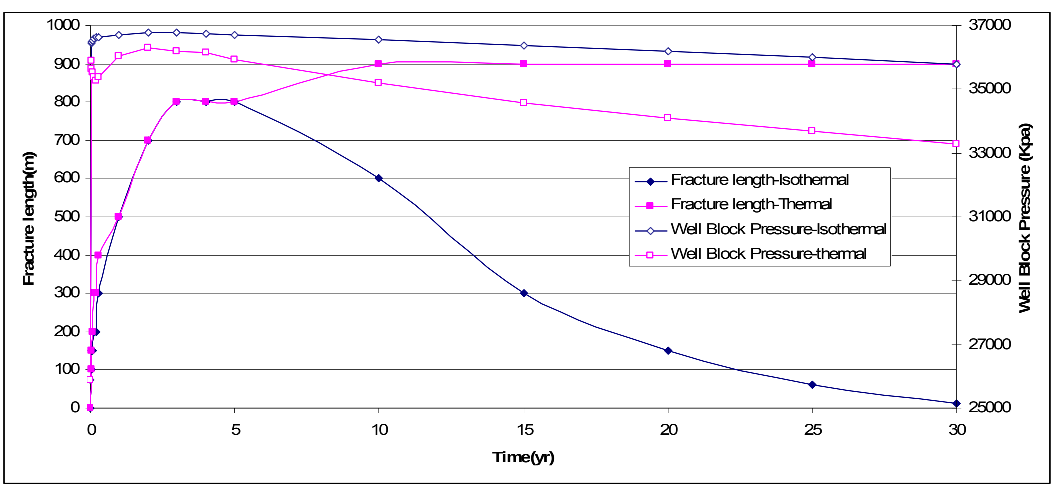


Figure 4: Fracture half length with 7.2E4 m^3/day injection rate with constant pressure boundary condition for thermal and isothermal model

In field CO_2 storage projects, more than a single well is drilled in the targeted formation and constant pressure boundary condition would not be a realistic condition for modeling multi-well injection scenario. Therefore the boundary condition was changed to a no-flow boundary condition so that the repeated well drillings pattern could be better simulated. Figure 5 compares the fracture length and well block pressure for the thermal and isothermal model. The block pressure in this model is again very close to the bottomhole injection pressure at which the fracture propagates. Since thermoelastic effects reduce stresses around the well, fracture propagates at lower pressure for the thermal model compared to the isothermal model. However due to the domination of poroelastic effects over heat transfer, the reduction in the fracturing pressure is small, and fracture length is affected very little by thermal effects. The fracture lengths for the two models are almost the same throughout the injection history. However, it should be kept in mind that the resolution of the fracture length is limited to a grid block size, and that will be more apparent in the following cases where fracture lengths are smaller.

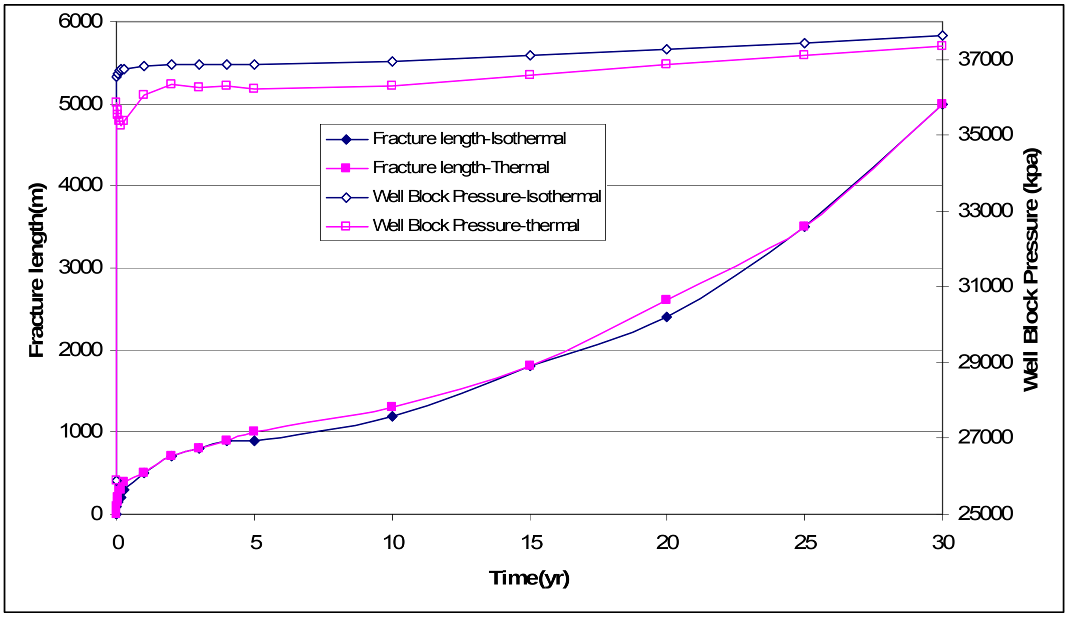


Figure 5: Fracture half length with 7.2E4 m^3/day injection rate with no flow boundary condition for thermal and isothermal model

If the injection rate is reduced, thermal diffusion (heat transfer) will dominate the process and fracture propagation. Therefore, due to thermal stress reduction, fracture length for for thermal model will be higher than for the isothermal model. Figure 6 shows the wellblock pressure and fracture length for thermal and isothermal model for two different smaller injection rates. As seen, the difference between the fracture length of the thermal and isothermal model increases as the injection rate is reduced. In general, one expects that the thermal effect of injection on fracture propagation is a function of pressure diffusivity, thermal diffusivity and injection rate.

Since the horizontal stresses in the caprock are higher than in the surrounding layers, vertical propagation of fracture does not occur either for thermal or isothermal model. However, in a feasibility study on CO_2 storage in Wabamun lake area, the stress contrast does not exist and thermal effects on heigh growth are important (Goodarzi et al, 2010).

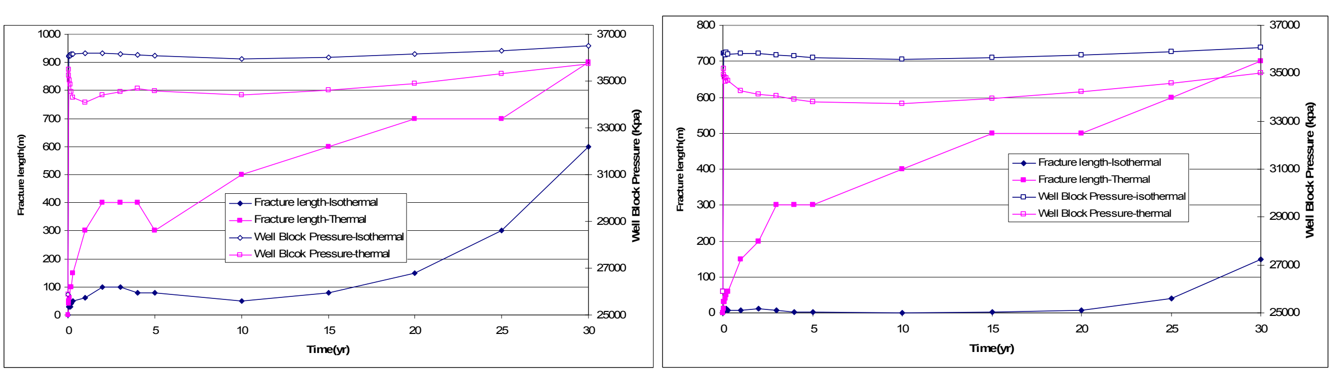
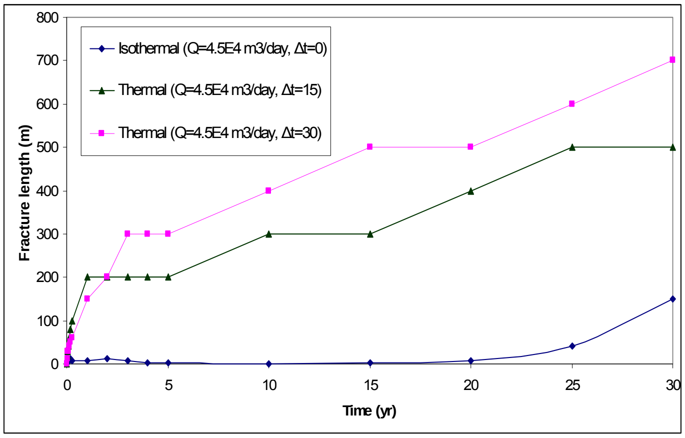


Figure 6: Fracture half length with no flow boundary condition with 5E4 m^3/day injection rate (left) and with 4.5E4 m^3/day injection rate (right)

The lack of smoothness seen on Figure 6 is caused by the resolution of the length being limited by the grid block size (we note that in the model the fracture propagates through a fixed grid). In order to get more accurate results, one would need to build different model grid for each case compatible with the expected fracture growth. However, we have chosen to use a common grid in order to facilitate comparison. This aspect will be studied further.

Thermal effects on fracture length

If thermoelasticity is the driving mechanism for fracture propagation, as the injection temperature reduces, the fracture growth rate increases. Figure 7 shows the fracture length for injection temperatures of 30, 45 and 60 C and injection rates of 4.5E4 m^3/day and 5E4 m^3/day. As the injection rate decreases and thermoelasticity dominates, the difference between the fracture length of the isothermal model and thermal model increases.



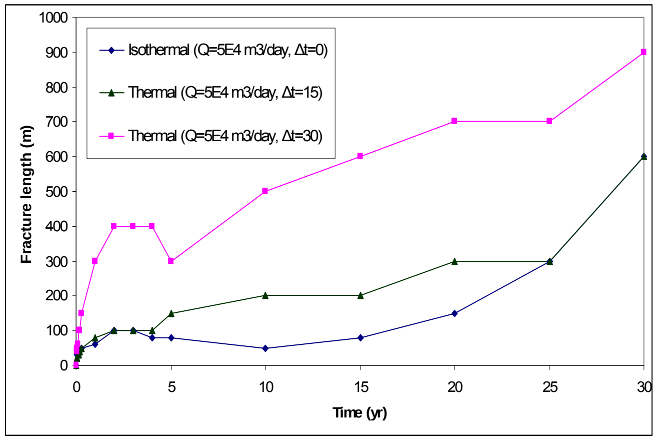


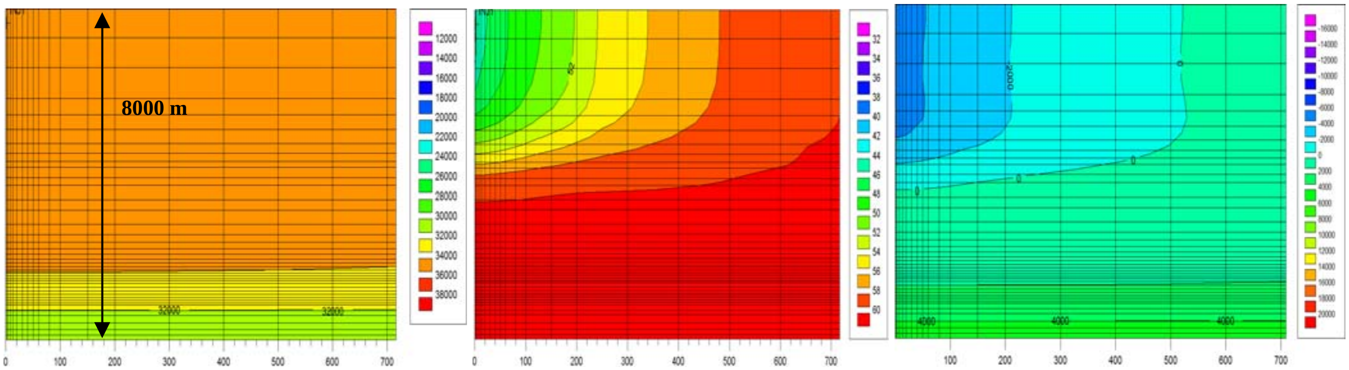
Figure 7: Effect of injection temperature on fracture length with 4.5 m^3/day injection rate (right) and 5 m^3/day injection rate (left)

Poroelasticity vs thermoelasticity

The phenomenon of the competition between poro and thermoelasticity described above can be clearly seen in Figure 8 and 9. These two Figures show pressure, temperature and minimum effective stress distribution for injection at two different rates. The model is a ¼ element of symmetry (for details see Goodarzi et al., 2010). These two sets of Figures are both zoomed on the near-well area with the well in the upper left corner, with the x-scale being linear and magnified to the fracture length at the end of injection, and y-scale being logarithmic.

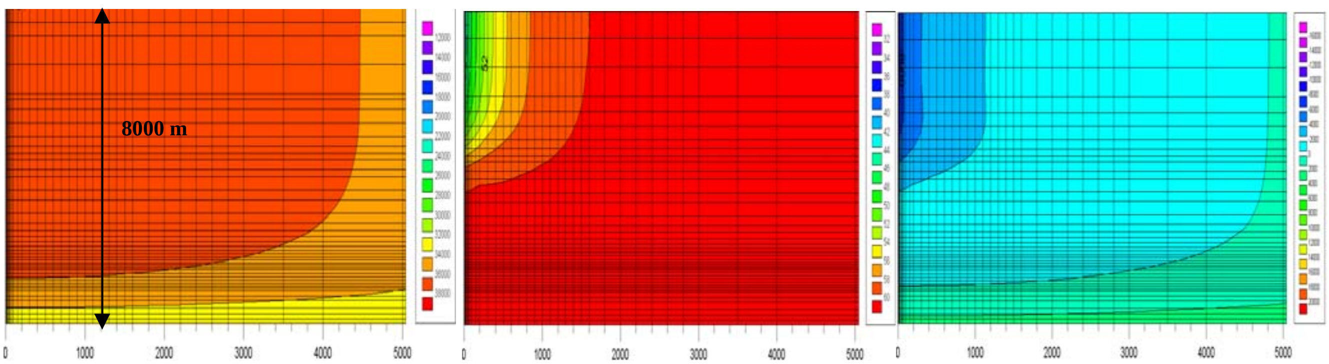
Effective stress distribution in both Figures shows negative values along the fracture length. However, for the higher injection rate (Figure 9), temperature front is much more behind the pressure front and therefore pressure is the main driving mechanism for fracture propagation and varying temperature would not affect the fracture length.

Heat transfer mechanisms are heat convection and diffusion. Fracture propagation strongly influence heat convection and temperature distribution. The relationship between heat diffusion and convection and the competition between them need to be studied further.



(a) (b) (c)

Figure 8: (a) Pressure (kpa) distribution, (b) Temperature (C), (c) Minimum effective stress (kpa) after 30 years of injection with 4.5E4 m^3/day injection rate



(a) (b) (c)

Figure 9: (a) Pressure distribution (kpa), (b) Temperature (C), (c) Minimum effective stress (kpa) after 30 years of injection with 7.2E4 m^3/day injection rate

Optimization possibilities

The concept demonstrated above is potentially very important for CO_2 storage optimization process with injection temperature being one of the important parameters. The simulations show that the thermal effects on fracture length are only significant at sufficiently small injection rates, but they will initiate fracture propagation. At high rates, fracture propagation will occur regardless of the injection temperature. One can therefore expect that in CO_2 injection, we will have to deal with fracturing in most cases (except for very low rates which will maintain injection pressure below the stresses in fully cooled target zone).

Given that the injection pressure and fracture propagation depends on injection temperature, the well injectivity, which is determined by the difference between the injection and far field reservoir pressure, and on fracture length, will also become a function of temperature.

The injection temperature itself is a function of the temperature of the source, process used to capture the CO_2, geographical location, etc. The cost of the transporting CO_2 to the wellhead is also a function of many variables; however, the temperature of the CO_2 in the pipeline determines its volume, and therefore compressor horsepower and pipeline diameter. The CO_2 Capture and Storage (CCS) project design can control the injection temperature by cooling or heating.

Therefore, injection rate and temperature should be both considered as optimization variables, when optimizating the storage process, based on maximizing the injectivity while maintaining the security of storage by limiting the fracture length,.
At small injection rates, if injected CO_2 has a lower temperature than reservoir temperature, in order to keep the fracture at a given length, either the injection rate must be decreased or CO_2 has to be heated to higher temperature before injection. On the other hand, higher temperature means higher capital and operating costs for transportation and injection. Injecting CO_2 at smaller rates with a fixed storage goal would also need drilling more wells in the targeted area. This would increase the drilling cost while heating or cooling CO_2 also changes costs for the storage project. These factors will play an important role in economics of a storage project. Our future work will be focused on developing more quantitative criteria for fracture pressure and propagation rates, and formulating a comprehensive algorithm for the optimization process described above.

Conclusions

This work investigated the thermal effects in CO_2 injection process in vertical wells for CCS using coupled fluid flow and heat transfer, geomechanics and fracturing simulation. The main conclusions are:

Injecting CO_2 at a temperature lower than reservoir temperature reduces the fracture pressure which leads to smaller injection capacity. Therefore coupling heat transfer model with flow and geoemchanical model is necessary for accurate simulation of CO_2 storage.

As the injection rate increases, thermal effects of injection on fracture propagation decreases, but tendency for fracturing increases regardless of thermal effects.. At small enough injection rates, fracture propagation is controlled primarily by the injection temperature, and is accelerated as injection temperature decreases. As a result, spontaneous fracturing is expected to take place in most CCS projects in vertical wells with injection temperature below reservoir temperature, unless the injection rates are impractically low. This is an important finding which will also have consequences for caprock integrity.

The dependence of fracture propagation and fracturing pressure on injection temperature opens interesting possibilities for optimization of CCS projects. The optimization process should consider as variables injection rate and temperature, well spacing and number of wells needed and associated capital and operating costs of CO_2 heating/cooling and pipeline and injection equipment.

The work needs to be extended for horizontal wells, because the well geometry will have a large effect both on fracture behavior and project optimization.

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